12/2/09

Response to DOI Comments
October 23, 2009

Comment 1: (Section Two: Overview)

We disagree with the statement on page 8 claiming that North Dakota has four mandatory federal Class I areas as defined under the Clean Air Act. Based on the legislation establishing Theodore Roosevelt National Park and the Clean Air Act, North Dakota has two mandatory federal Class I areas (i.e., Theodore Roosevelt NP and the Lostwood Wilderness Area). The entire acreage of Theodore Roosevelt NP is one Class I area under the Clean Air Act, and should be treated as such for all protection purposes, such as assessing for increment consumption and calculating visibility impacts.

Response: North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The Department considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

   Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Ranch Unit.

Comment 2: (Section Three: Plan Development and Consultation)

The plan addresses the State of Minnesota's request for NDDAQ to analyze the feasibility of reducing electrical generating unit (EGU) emissions in North Dakota to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NO_X). While NDDAQ listed reasons why it did not believe the State of Minnesota's request was supported by assessments of impact, we request that ND supply the emission rates established by the regional haze plan from EGUs across the State so we and the public can be informed of any differences between the request from Minnesota and the final requirements of the NDDAQ plan.

The U.S. Environmental Protection Agency (EPA) will need to review any discrepancy between the Minnesota regional haze plan and the North Dakota regional haze plan during its review and approval process. In addition, we agree with NDDAQ that the EPA should address the significant contribution of international emissions, particularly from power generation in Canada, in support of NDDAQ's efforts for reasonable progress.

Response: We believe the lb/10^6 Btu metric proposed by Minnesota is inappropriate since it is not based on the four factors that must be considered for a reasonable progress analysis as required by rule and law. We believe cost must be considered, especially on a dollar per deciview of improvement basis.

Comment 3: (Section Four: Monitoring Strategy and Other Implementation Plan Requirements)

We note that the language in the footnote of Table 4.1 implies that the visibility monitoring conducted under the cooperative Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) system at Theodore Roosevelt NP is covering more than one Class I area. While the monitoring is at one unit, it is representative of all three units of that one Class I area.

We appreciate NDDAQ's efforts to enhance monitoring of visibility with additional collection of data. We support the ongoing efforts to collect and periodically update state-wide inventories of pollutant emissions that may contribute to the visibility impairment noted on page 24 of the Plan.

Response: The footnote to Table 4.1 will be changed.

Comment 4 (Section Five: Baseline and Natural Conditions and Uniform Rate of Progress for North Dakota Class I Areas)

As previously noted, we do not agree with the statement on page 30 that North Dakota has four distinct Class I areas. We do agree that the IMPROVE data collected at Theodore Roosevelt NP sufficiently tracks the long-term visibility conditions across the entire park and can be used for implementing the requirements of the regional haze rule.

Response: See response to Comment 1.

Comment 5: (Section Six: Sources of Visibility Impairment in North Dakota Class I Areas)

We appreciate the presentation of the Western Regional Air Partnership (WRAP) assessment of sources of visibility impairment at the two North Dakota Class I areas. In particular, Table 6.6 is a useful summary of North Dakota's contribution to impairment listed by component of light extinction. This forms a baseline to compare projected conditions in the reasonable progress section of the Plan. We ask that NDAQ clarify in the narrative that the sulfate and nitrate results are based on regional modeling using the CAMx-PSAT source apportionment tool, while the analyses of weighted emissions potential for organic carbon (OC), elemental carbon (EC), and particulate matter (PM) are based on emissions and residence time, not modeling. Figures 6.1, 6.2, 6.7, and 6.8 would be more informative if they also included 2018 results for sulfate and nitrate as is shown in the other figures for OC, EC, and PM.

Response: The Department will clarify that sulfates and nitrates are based on WRAP's tracer analysis modeling results and the results for the other pollutants are based on WRAP's weighted emissions potential analysis.

WRAP does not provide results for Case PRP18b using their tracer analysis (only Base 18b). We have included the weighted emission potential (WEP) analysis for SO_2 and NO_x that includes 2002 and PRP18b results. However, we disagree with the WRAP's estimate of oil and gas NO_x emissions in 2018.

Comment 6: (Purpose of the BART Program)

The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

Response: The determination of Best Available Retrofit Technology (BART) is based on the assessment of five factors: 1) Cost of compliance, 2) the energy and nonair quality environmental impacts of compliance, 3) any existing pollution control technology in use at the source, 4) the remaining useful life of the source and 5) the degree of improvement in visibility which may be reasonably be anticipated to result from the use of such technology (CAA, Sec. 169A(g)(2)). The Department has considered all five factors in its BART determinations. EPA, in Step 5 of the BART Guideline states "…you are free to determine the weight and significance to be assigned to each factor". In determining BART, visibility improvement was generally not weighted as heavily as the cost of compliance because we believe the single source modeling required by the BART guideline does not give a true representation of the degree of improvement in visibility **which may reasonably be anticipated to result from the use of the technology**.

We believe the cumulative visibility effects analysis promoted by DOI is scientifically unsound and not in accordance with rule or law. Adding the maximum improvement value (or 98^{th} percentile) at one Class I area to the maximum improvement at another Class I area does not account for these maximums happening at different times. In addition, DOI has not defined which Class I areas should be added together to achieve the cumulative impact. This makes the analysis arbitrary. The single source modeling under BART does not provide a realistic estimate of visibility improvement of a given technology. Creating a "cumulative effects" analysis based on the flawed BART analysis only compounds the inaccuracy and misleads the reader of the SIP. In addition, the BART Guideline only requires an evaluation of the change at each receptor. It does not require adding these changes together.

Comment 7: (Five-Step BART Process)

Step 1: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES
Except for Great River Energy's (GRE's) analysis for NO_x from Coal Creek, all of the other SO_2 and NO_x analyses included a reasonable suite of options.

We also have some general comments that apply to all of the PM_{10} analyses. We believe that the BART analyses are deficient in that they neither address upgrades to the existing Electrostatic Precipitators (ESPs) or propose limits that realistically reflect the capabilities of those existing ESPs, as well as the proposed new baghouses, to control filterable PM. EPA's BART Guidelines (Guidelines) advise:

- "…it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control equipment."
- "…for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devises, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, you should consider requiring those sources with electrostatic precipitators (ESPs) performing below currently achievable levels to improve their performance."

Although all of these sources have ESPs in place, none of them except Stanton Unit #1 is currently achieving a level of performance equivalent to the 0.015 lb/mmBtu proposed for ESPs at sources such as Peabody's Thoroughbred and LG&E's Trimble County projects in Kentucky. Furthermore, EPA has recently issued a permit limiting the Desert Rock facility to 0.010 lb/mmBtu filterable PM_{10}, new baghouses are being permitted at 0.009 – 0.012 lb/mmBtu in

Virginia (Virginia Hybrid Energy Center) and Wyoming (Dry Fork, WYGEN 3), and ND DOH proposed to permit the Gascoyne project at 0.012 lb/mmBtu. Instead, the limits on filterable PM_{10} proposed by NDDAQ are two – to – three times the emission rates measured by stack testing and cited by NDDAQ. While we understand that a certain "safety margin" must be allowed, we believe that the BART limits should be set to encourage continued good operation and maintenance of the pollution control equipment.

Response: The comment regarding the suite of options evaluated for NO_x controls at Coal Creek will be addressed later under the specific comments on the Coal Creek BART determination.

Regarding BART for PM at the BART eligible sources, in 2008 the emission rate at these sources ranged from 0.004 lb/10^6 Btu to 0.015 lb/10^6 which is generally comparable to levels achieved under BACT. The Department evaluated recent stack tests at the various power plants and found that emissions could vary up to 0.061 lb/10^6 Btu at Leland Olds Unit 1. The variation in the PM emission rate is probably due to a variation in the coal combusted (i.e. higher ash, different ash resistivity, etc.) and/or variations in the boiler and ESP operations. Sources must be able to comply with a BART limitation at all times unless specifically exempted. The Department chose to reduce the current allowable down from 0.10 lb/10^6 to 0.07 lb/10^6 Btu. This allows the sources to maintain continuous compliance yet requires the source to assure the ESP is working properly. The Department also reviewed the effect of PM from the BART sources on visibility. Based on the maximum 24-hour emission rate for the baseline period (5 years) the maximum impact was 0.027 deciviews (98^{th} percentile). This amount of impact is considered very small and inconsequential. The newest ESP at the BART sources is 30 years old. The Department's review found that it was not cost effective to replace them and any improvement would not provide appreciable visibility improvement. We have concluded that 0.07 lb/10^6 Btu is a reasonable emission limit after considering the five statutory factors.

Comment 8:

Step 3: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES
The ability of SCR to reduce emissions, as assumed by NDDAQ, was inconsistent and sometimes underestimated. For example, for the LNB/OFA+SCR option, GRE, Basin Electric Power Cooperative (BEPC), and NDDAQ sometimes assumed 0.07 lb/mmBtu for all averaging periods. However, for example, the WY Department of Environmental Quality has issued permits for new EGUs requiring that they meet 0.05 lb/mmBtu over averaging periods of 24-hours and 30-days. Furthermore, EPA's Clean Air Markets (CAM) data (Appendix A) and vendor guarantees show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis. GRE, BEPC, and NDDAQ have not provided any documentation or justification to support the higher values used in their analyses. Our review of operating data (Appendix A) suggests that a NO_X limit of 0.06 lb/mmBtu is appropriate (with an adequate "safety-margin") for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates. When the annual NO_x reductions are underestimated, the cost-effectiveness of the control option is negatively affected.

Response: The 0.05 lb/10^6 Btu limit in Wyoming was for the Dry Fork Plant which is a new plant and has not demonstrated that it can meet that limit.

DOI claims that SCR can achieve 90% removal efficiency. The Department believes this is true for new units but not for retrofits. The EPA Air Pollution Control Cost Manual states "In practice, SCR systems operate at efficiency in the range of 70% to 90%." EPA's Air Pollution Control Technology Fact Sheet for SCR states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09) EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90+% control assumed by APS, is appropriate". The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

Comment 9:
Step 4: EVALUATE IMPACTS AND DOCUMENT RESULTS
The cost of SCR was consistently overestimated. EPA's BART Guidelines recommend use of the OAQPS Control Cost Manual. Neither Minnkota Power Cooperative (Minnkota), GRE, BEPC, nor NDDAQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and none used the recommended Control Cost Manual. This resulted in much-higher SCR costs than suggested by available literature (see Appendix B cost summaries) which shows SCR costs ranging from \$50 - \$267/kW. As recommended by the BART Guidelines, we applied the OAQPS Control Cost Manual to the EGUs and derived costs that fell within the Appendix B cost-survey range. As a result, we believe that capital and annual costs are overestimated by NDDAQ.

According to EPA's BART Guidelines, "the basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."

EPA's belief that the Control Cost Manual should be the primary source for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to NDDAQ:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based

on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

We are especially concerned about the lack of justification and support for the estimates of costs for reheating the exhaust gas streams to facilitate addition of “tail-end” SCR. Reheat costs are a critical issue affecting the economic feasibility of SCR, and, even in those cases where some data were presented (by GRE), it was still not adequate for us to be able to understand the assumptions that formed the bases for the natural gas usage estimates. Furthermore, we are concerned that the costs of catalyst, ammonia, electricity, and natural gas were inflated beyond what we typically see, or what is projected by the Energy Information Administration (EIA) with respect to future natural gas prices. Finally, we are concerned that this critical cost was simply scaled from a few examples and applied to other SCR analyses—we believe that it deserves individual analyses specific to each case.

Response: The DOI used the EPA Air Pollution Control Cost Manual (February 1996) to estimate the capital cost and operating costs for the SCR system. The DOI did not use the most current version of this manual which is dated January 2002. The EPA Air Pollution Control Cost Manual (both versions) is significantly out-of-date for estimating costs for SCR. This can be seen from the recently published results of EPA’s review of the Four Corners Power Plant BART analysis. In the Advanced Notice of Proposed Rulemaking (August 28, 2009), EPA published the Consultant’s, EPA’s and the National Park Service’s estimate of the cost for NO_x controls. The annualized cost of SCR was as follows:

Unit	Consultant	EPA	NPS
1	$22,297,000	$16,599,600	$2,983,000
2	$23,634,000	$17,851,500	$3,052,010
3	$23,173,000	$16,962,000	$3,497,117
4	$55,755,000	$39,810,900	$9,838,997
5	$55,755,000	$39,810,900	$9,213,942

The NPS cost estimate is 4-6 times lower than EPA’s estimate.

For SCR alone the cost effectiveness was:

Unit	Consultant ($/ton)	EPA Cost ($/ton)	NPS Cost ($/ton)
1	4,343	3,758	1,558
2	5,484	4,803	1,469
3	4,582	3,646	1,684
4	4,872	4,341	1,185
5	4,872	4,330	1,357

It would appear the NPS is underestimating annualized SCR costs by as much as a factor of 6 and cost effectiveness by as much as a factor of 3. The discrepancy between the annualized cost and the cost effectiveness is apparently due to the NPS overestimating the effectiveness of SCR.

Based on this apparent underestimation, it appears the costs provided by the consultants and the Department's estimates are similar to EPA estimates and are reasonable. Any estimate by the FLM of cost on a dollar per deciview basis would be similarly flawed.

As pointed out earlier, the OAQPS Control Cost Manual is out-of-date. EPA accepted estimates based on the CUE Cost Model for the Four Corners Power Plant BART analysis. Since the OAQPS Control Cost Manual is out-of-date and drastically underestimates control costs, we believe the CUE Cost Model provides a more realistic estimate of the costs.

Comment 10: (Step 5: Visibility Improvement)

A) DOI believes it is appropriate to consider both the degree of visibility improvement as well as cumulative effects.

B) DOI is concerned that the Department did not provide the total improvement for each BART option.

Response: The total improvement under BART is not the best metric for addressing visibility associated with each option since the single source modeling under BART overpredicts (by a factor of 5-7) the actual improvement in North Dakota. Incremental differences in improvement provides an easy way to evaluate the visibility improvement benefits of one option over another. The difference is equivalent to the total improvement of one option minus the total improvement of the other option. Providing the total improvement will mislead the reader of the SIP because of the overprediction. However, this information can be extracted from the analyses conducted by the operators of the BART sources.

C) DOI is concerned about the difference in their modeling for Leland Olds Unit 2 and the Department's and Basin Electric's modeling results (the latter two sets of results agree closely).

Response: There are bound to be differences in modeling results when different model settings and options are used as well as different receptor grids. One error noted in the DOI modeling results was the input for the maximum 24-hour SO_2 emission rate for Unit 2. DOI used 17,610 lb/hr plus 1,581 lb/hr for sulfate. Unit 2 had a maximum 24-hour SO_2 (includes SO_4) of 12,205 lb/hr during the baseline period (2000-2004). DOI apparently used an SO_2 + SO_4 emission rate based on maximum future sulfur content. This is incorrect since current visibility conditions (12,205 lb/hr) are compared to conditions after controls are applied. The BART Guideline states "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)". The meteorological data used by the Department is from 2000-2004. Use of potential <u>future</u> uncontrolled emissions for the pre-control scenario is inconsistent with the BART guideline. The Department also noted that this error carried over into the emission rates for other pollutants. This error will provide a much greater improvement in visibility as found by the DOI.

Comment 11: It appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

Response: The Department does not necessarily agree with this statement. There are situations in North Dakota where reduction in NO_x has very little impact on visibility. This can be seen from the AVS I analysis. A 65% reduction NO_x (2,356 tpy) only provided a 0.01 deciview improvement in the average of the 20% worst days.

Comment 12: DOI recommends more emphasis on the dollar per deciview metric.

Response: There was no established data base for this metric when the BART analyses were developed and when the Department was making its decisions. Even the DOI's data is not very useful since the EPA has not approved the BART determinations in that database. Again, the single source modeling does not reflect the true visibility improvement. It may be more realistic in some states than in others. Therefore, the comparison of $/deciview in North Dakota to $/deciview in another State is not an apples-to-apples comparison. The Department has considered the incremental visibility improvement between BART options. We believe this is the best metric given the limitations of single source modeling to provide realistic estimates of visibility improvement.

Comment 13: For several units, NDDOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where NDDOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where NDDOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where NDDOH has proposed alternative limits, both should be required.

There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

Response: The DOI has requested that the sulfur dioxide limitations be written as 95% reduction <u>and</u> 0.15 lb/10^6 Btu instead of 95% reduction <u>or</u> 0.15 lb/10^6 Btu. Coal quality data suggests that the source may not be able to comply with the 0.15 lb/10^6 Btu limit when the maximum sulfur coal is received. This would make the requested standard impossible to meet for high sulfur coal. The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control <u>**or**</u> [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to any source in North Dakota except for NO_x at Coal Creek Station.

The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts was based on full load and worst case sulfur (i.e. highest 24-hour emissions). The Department asked the EPA if a mass per unit of time limit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that establishes the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated "we think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that establishes the BART limits.

Comment 14: DOI does not believe Heskett Unit 2 should be exempt from the BART requirement.

Response: The Department is reevaluating the status of Heskett Unit 2. This unit will be addressed in a supplement to this SIP revision.

Comment 15: DOI believes the 70% reduction requirement at Heskett Unit 2 is misleading.

Response: The 70% reduction is a requirement that was placed in the draft Permit to Construct. The calculations that were provided are accurate based on the coal quality expected. The Department will clarify that the permit requirement (70% reduction) is not an actual reduction from current emissions.

<u>Coal Creek BART Determination</u>

Comment 16: Low NO_x burners and Over-Fire Air should have been considered coupled with SCR.

Response: The Department evaluated SCR at an emission rate of 0.043 lb/10^6 Btu (annual average) which is equivalent to 0.05 lb/10^6 Btu on a 30-day rolling average basis. This is the same as the lowest emission rate in the RBLC. We believe a lower emission rate is not achievable on a continuous basis. Because Coal Creek is already equipped with LNB and a form of overfire air, the modifications of these systems is not expected to reduce emissions below 0.043 lb/10^6 Btu.

Comment 17: NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **<u>or</u>** 95% reduction on a 30-day rolling average basis. The proposed scrubber upgrades will each result in an approximately one dv improvement in visibility at Theodore Roosevelt NP and 1.9 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubber, but recommend that the limits require **<u>both</u>** 95% control **<u>and</u>** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: The Department's BART determination is based on upgrading the existing wet scrubber to 95% efficiency, not the addition of a new wet scrubber. See response to Comment 13 regarding the BART limit.

Comment 18: NDDAQ is proposing LNB + SOFA at 0.17 lb/mmBtu on a 30-day rolling average basis as BART for NO_X. As a result, visibility would improve by 0.10 dv at Lostwood and 0.19 dv cumulatively.

Response: See response to Comment 6, Paragraph 2.

Comment 19: NDDAQ has underestimated the effectiveness of SCR at only 80% control efficiency.

Response: See response to Comment 8.

Comment 20: NDDAQ has overestimated the costs of SNCR and SCR. Many of the costs associated with SNCR and SCR presented by GRE and NDDAQ were not supported by GRE's documentation. Costs associated with lost ash sales and ash disposal were not adequately justified. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as GRE did, to provide sufficient supporting documentation of its costs. Our application of the EPA Control Cost Manual yielded much lower cost estimates for SNCR and SCR.

Response: See response to Comment 9.

Concerning the inclusion of sunk costs of ash sales infrastructure, an assessment of the effect of removing sunk costs from the calculations has been performed and added to the BART determination. If the sunk costs for the ash sales infrastructure are disregarded, then the annualized cost for SNCR would be $21,750,000; the cost effectiveness would be $8,122 per ton; and the incremental cost would be $19,692 per ton. This change improves the favorability of the SNCR alternative by only 5%, an insignificant improvement that does not change the choice for BART.

On the matter of the possibility of lost ash sales, DOI stated elsewhere in its comments: "If ash sales are not adversely affected, addition of SNCR becomes a reasonable BART selection." However, neither DOI, EPA nor others have provided evidence to support the opinion that SNCR and its associated use of ammonia will not negatively impact GRE's ash sales; in fact, there is some evidence to the contrary. GRE emails dated 8/8/08 and 8/17/08 provide additional information on this issue, as does a summary of a University of Kentucky study on the matter. After considering all the information available, NDDAQ reached the following conclusions.

- SCR and SNCR use at Coal Creek Station will likely result in ammonia in the fly ash.
- The level of ammonia in the fly ash cannot be predicted with a reasonable certainty.
- The maximum level of ammonia in fly ash that would still avoid negative impacts on the salability of the ash cannot be predicted.

Therefore, NDDAQ cannot determine with reasonable certainty that SCR or SNCR will not result in a level of ammonia in the ash that could reduce or eliminate future ash sales. Any regulator who determines that SCR or SNCR will not jeopardize ash sales would be obligated to present the evidence in support of that position. While another regulator might determine that even a small improvement in visibility is worth GRE taking the risk of lost ash sales, making a wrong decision will inflict a significant financial penalty on GRE and send ash to a landfill, or be treated as a hazardous waste (depending on current rule development), instead of it being used beneficially. Having considered all of the information available, the NDDAQ BART determination on this matter remains unchanged.

Furthermore, in a BART and PSD analysis for the Omaha Public Power District Nebraska City Station Unit #1 coal boiler (Construction Permit Number CP07-0049, 2/26/09 fact sheet, pg. 17), Nebraska DEQ determined SCR was not BART in part because … “ammonia used in the system would cause the ash to be contaminated, thereby jeopardizing the current beneficial reuse of a portion of the ash produced by NCS Unit 1.”

Comment 21: We conclude that SNCR is BART for control of NO_X emissions from GRE Coal Creek Units #1 and #2.

Response: See Comment 20 and response concerning lost ash sales.

Comment 22: NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated.

Response: Tables showing the visibility impacts of the cost effective control strategies will be added to the GRE Coal Creek BART analysis.

Comment 23: NPS’ analysis of addition of SNCR indicates that visibility would improve by 0.17 dv at Lostwood and 0.32 dv cumulatively. This yields a cost-effectiveness of $17.2 million per dv at Lostwood WA and $9.2 million per dv cumulatively when Theodore Roosevelt NP is included, which we believe to be reasonable based upon BART determinations and proposals we have seen nationwide to date. NPS’ estimates for addition of SNCR show cost-effectiveness values below the $17 - $21 million per cumulative dv that NDDAQ accepted for adding SNCR at Stanton #1. Considering that the BART program is intended to improve visibility, it follows that any cost-effectiveness value below the costs per dv accepted by NDDAQ at Leland Olds #1 and Stanton should also be acceptable at Coal Creek.

Response: See response to Comment 6.

<u>Stanton Unit 1 Bart Determination</u>

Comment 24: On page 15 of the comments, the DOI states that “Great River Energy (GRE) operates the 256 MW Stanton Station near Stanton, ND.”

Response: The nameplate capacity of the Stanton Station is 200 MWe, not 256 MW as stated by DOI. The National Park Service was informed by the Department in an October 21, 2009 email that the nameplate capacity of the Stanton Station is 200 MWe. It should be noted that the BART determination is being conducted for Stanton Station Unit 1, not the entire Stanton Station (which consists of Stanton Station Unit 1 and Unit 10). Stanton Unit 1 can supply steam that will produce 140 – 170 MWe.

Comment 25: On page 16 of the comments, the DOI states, "We believe that higher control efficiency is warranted for both the lignite and PRB sub-bituminous scenarios". The DOI goes on to state that a facility burning coal with an uncontrolled SO_2 emission rate of 2.4 lb/MM Btu for lignite and 1.6 lb/MMBtu on PRB "should be capable of at least 93% control and achieve an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis[11]". Footnote 11 in the DOI comments states, "Please see the entry in Appendix D for the permit issued by Wyoming to Black Hills Power for its WYGEN3 project".

Response: The DOI states a SD/FF at Stanton #1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The DOI attempts to support this position by referencing the WYGEN3 facility permit. Although the WYGEN3 facility does have a 0.09 lb/MMBtu SO_2 emission limit, according to the EPA RACT/BACT/LAER clearinghouse, the 0.09 lb/MM Btu SO_2 emission limit is on a <u>12-month rolling average</u> basis, not a <u>30-day rolling average</u> basis. Also, the RACT/BACT/LAER clearinghouse does not list a required SO_2 removal efficiency. If the WYGEN3 facility burns low-sulfur coal, the facility could comply with the 0.09 lb/MMBtu emission limit with SO_2 control efficiencies below 90%. Furthermore, it is the Department's understanding that the WYGEN3 facility has yet to operate and demonstrate that the SO_2 emission limit can be achieved. Based upon these facts, the WYGEN3 facility permit does not support the DOI position that a SD/FF at Stanton Station Unit 1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis.

The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an SO_2 control efficiency of 90%.

Comment 26: On page 16 of the DOI comments, the DOI states, "Because the larger Stanton Unit #10 also located at this site is achieving less 0.06 lb/MMBtu on an annual basis (presumably burning PRB coal) using the same SD/FF technology proposed for Stanton Unit #1, NDDAQ should explain why a newer installation of that technology at Stanton #1 cannot perform as well, at least on PRB coal".

Response: The DOI incorrectly states that Stanton #10 is larger than Stanton #1. In fact, Stanton #10 (with a heat input of approximately 642 MM Btu/hr) is approximately 2.8 times <u>smaller</u> than Stanton #1 (with a heat input of approximately 1,800 MM Btu/hr).

The DOI states that Stanton #10 emitted SO_2 at an emission rate of 0.06 lb/MM Btu and asks the Department to explain why Stanton #1 cannot perform as well as Stanton #10 when burning PRB coal. Although the Stanton #10 facility has recently emitted SO_2 at an emission rate of 0.06 lb/MM Btu, based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%. The dry scrubber technology proposed as BART for Stanton #1 is expected to achieve an SO_2 control efficiency of 90%, so Stanton #1 <u>will be</u> expected to perform as well as Stanton #10.

Comment 27: On page 16 of the DOI comments, the DOI states, "It is likely that increasing the SD/FF efficiency to achieve 0.09 lb/mmBtu would be even more cost effective on a $/ton basis."

Response: The DOI provides no basis for this comment. The Department maintains the position that 90% control is a reasonable control efficiency for a SD/FF system and that the Stanton Station Unit 1 would not be able to meet an SO_2 emission limit of 0.09 lb/MM Btu when combusting higher sulfur coals.

Comment 28: On page 17 of the DOI comments, the DOI states, "We recommend limits of 0.09 lb/mmBtu and 93% reduction on a 30-day rolling average for both fuels based upon recent determination by other states for EGUs burning coals with similar uncontrolled emissions. Even if coal quality deteriorates to the anticipated worst-case 2.4 lb/mmBtu, 96% control would still meet the 0.09 lb/mmBtu limit. We also recommend short and long-term absolute (e.g., lb/hr, tpy) caps on emissions to insure that emissions will not increase greatly over time". The DOI reiterates this comment on page 20 of the DOI comments.

Response: DOI has requested that the sulfur dioxide limitations be written as 93% reduction <u>and</u> 0.09 lb/MM Btu for both fuels instead of 90% reduction <u>or</u> 0.16 lb/MM Btu for PRB <u>or</u> 0.24 lb/MM Btu for lignite. Coal quality data suggests that the source would not be able to comply with the 0.09 lb/MM Btu limit when the maximum sulfur content coal is received and emissions are controlled at 90%. This would make the requested standard impossible to meet for high sulfur coal with a 90% reduction requirement. The DOI suggests that the facility can simply control at efficiencies greater than 90% (i.e. 96%); however, the Department's position is that a SD/FF operating at Stanton Station #1 is capable of 90% SO_2 control on an on-going basis, not greater than 90% control as suggested by DOI.

The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states, "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control **<u>or</u>** [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to this source.

The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts were based on full load. The Department asked the EPA if a mass per unit of time unit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that established the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated, "We think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that established the BART limits.

Comment 29: On page 17, the DOI states, "We believe that NDDAQ should have included SOFA with tail-end SCR with reheat in its analysis".

Response: The Department analyzed SCR with reheat in the BART analysis. A 90% control efficiency for SCR with reheat was assumed. For retrofits, the Department believes that a 90% control efficiency for SCR with reheat is highly optimistic and that 80% control is reasonable. It should be noted that conducting the BART analysis using an 80% control efficiency would make the cost of SCR with reheat even more cost prohibitive.

In the Department's judgment, SOFA with SCR with reheat would not attain greater than 90% NO_x control at Stanton #1. Since SOFA with SCR with reheat would be more expensive than SCR with reheat (which has already been determined to be cost prohibitive assuming a 90% control efficiency), it can be concluded that an analysis of SOFA with SCR with reheat would also be considered to be cost prohibitive.

Comment 30: On pages 18 and 20 the DOI indicates that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. The DOI requests that the Department document and justify the SCR with reheat cost estimate.

Response: The DOI requests that the Department document and justify the SCR with reheat cost estimate for Stanton #1. The Department considers the cost estimate of SCR with reheat submitted with the GRE BART analysis to be extensively documented and the Department has verified the cost estimates.

The DOI states that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. See response to Comment 9.

Comment 31: On page 21 of the comments, the DOI states, "We believe that SCR may represent BART, especially when the modeling issues identified in other reviews are resolved".

Response: The Department has eliminated high-dust SCR as technically infeasible and low-dust SCR with reheat has been eliminated based on cost. The DOI has questioned the Department's cost estimates for SCR with reheat and the Department has demonstrated that the costs as presented are reasonable (see response to Comment 9). Based upon a consideration of all of the factors, the Department maintains the position that SCR does not represent BART at Stanton Station Unit 1.

<u>Leland Olds Unit 1 BART Determination</u>

Comment 32: NDDAQ did not evaluate the impact of the new wet scrubber at Unit 1 versus the baseline condition.

Response: The Department evaluated the difference in visibility impact between the top two SO_2 control technologies, a wet scrubber and spray dryer. As indicated by the BART Guideline, Step 5, a determination of the <u>net</u> visibility improvement is to be made. Our analysis is consistent with the BART Guideline. The most efficient control option (wet scrubber) was selected as BART. The amount of visibility improvement versus the baseline may be extracted from BEPC's analysis. The Department did not present this result since we believe it is incorrect and misleads the reader.

Comment 33: DOI recommends that the SO_2 limit be written as 0.15 lb/10^6 Btu <u>and</u> 95% reduction.

Response: See response to Comment 13.

Comment 34: DOI believes SOFA + SCR can achieve 83% NO_x removal.

Response: As pointed out in the Advanced Notice of Proposed Rulemaking for the Four Corners Power Plant, the Arizona DEQ determined that 75% control was appropriate following low NO_x burners at the Coronado Generating Station. Leland Olds 1 is equipped with low NO_x burners. We believe 75% reduction for the retrofit of a 43 year old plant is appropriate. Reducing the emission rate to 0.05 lb/10^6 Btu achieves 212 tons per year additional NO_x reduction. The cost effectiveness is then $8,888/ton to $12,784/ton. These costs are still considered excessive and SCR + SOFA is not BART.

Comment 35: NDDAQ did not evaluate the visibility benefits of any of the technically feasible options except for the proposed basic SOFA + SCR.

Response: The cost analysis eliminated SCR, coal reburn + SCR, coal reburn + SOFA and SNCR + boosted SOFA on either a very high cost effectiveness basis or a very high incremental cost basis. This left SOFA + SNCR as the most efficient control option. This option was then modeled to determine the visibility effects.

Comment 36: NDDAQ is proposing addition of a new wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu <u>**or**</u> 95% reduction on a 30-day rolling average basis. We have estimated that the proposed new wet scrubber will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.4 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require <u>**both**</u> 95% control <u>**and**</u> 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 37: Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR to LOS #1 yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included. NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $12.6 – $32.3 million per dv cumulatively. We would normally consider costs above $20 million/dv to be above the average that most states/source are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.

Response: SOFA + SCR has an estimated cost of $8,888 - $12,784/ton of NO_x removed. The incremental cost would be approximately $15,748/ton to $25,319/ton over the next most efficient option. It is clear that SOFA + SCR, or SCR alone, is not cost effective for this unit.

Comment 38: NDDAQ underestimated the effectiveness of adding SCR to LOS #1. Outlet emissions projected by NDDAQ for SCR at 0.07 lb/mmBtu represent only a 75% SCR control efficiency We believe that a combination of combustion controls (e.g., SOFA) plus SCR can achieve 0.05 lb/mmBtu, and represents BART.

Response: See response to Comment 8. This is consistent with other BACT determinations, especially for retrofits.

Comment 39: NDDAQ overestimated the costs associated with adding SCR to LOS #1.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS, to provide sufficient supporting documentation of its costs.

Response: See response to Comment 9.

Leland Olds Unit 2

Comment 40: DOI suggests we investigate the differences in their modeling results and the Department's and BEPC results.

Response: The Department has investigated the DOI modeling – See response to Comment 10(c). The DOI modeling is not consistent with the BART Guideline. The Department's and BEPC modeling is consistent with the guideline.

Comment 41: NDDAQ is proposing to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We recommend 0.15 lb/mmBtu **and** 95% reduction on a 30-day rolling average basis.

Response: See response to Comment 13.

Comment 42: We re-modeled LOS #2 assuming that the new wet scrubber would reduce SO_2 emissions to 0.15 lb/mmBtu and held all other emissions to their baseline rates. Our results estimate that the scrubber would improve visibility by 5.6 dv at Theodore Roosevelt NP and 9.4 dv cumulatively when Lostwood WA is included.

Response: See response to Comment 10(c). The much higher future emission rate, which is not consistent with the BART Guideline which requires use of the baseline emission rate, yielded the higher inaccurate result.

Comment 43: We agree with NDDAQ's estimates of control effectiveness, but suggest that, if ASOFSA can reduce emissions to 0.5 lb/MMBtu as estimated by NDDAQ, then addition of SCR at 90% as assumed by NDDAQ could bring emissions down to 0.05 lb/mmBtu.

Response: As pointed out in our response to Comment 8, 80% efficiency is a better number for retrofit of SCR. The Department did use 90% efficiency for SCR + ASOFA.

Comment 44: NDDAQ overestimated the costs associated with adding SCR to LOS #2.Our application of the EPA Control Cost Manual yielded much lower cost estimates for SCR. Many of the costs associated with SCR presented by BEPC and NDDAQ were much higher than we have seen presented at similar facilities and were not supported by BEPC's documentation. More reliance should be placed upon use of the EPA Control Cost Manual when the source fails, as BEPC did for LOS #2, to provide sufficient supporting documentation of its costs.

Response: See response to Comment 9.

Comment 45: We re-modeled LOS #2 and estimate that ASOFA + SCR would improve visibility by 2.3 dv at Theodore Roosevelt NP and 4.1 dv cumulatively when Lostwood WA is included. Our higher control-effectiveness results show that we are estimating that removing a ton of NO_x has greater benefits than estimated by BEPC/NDDAQ.

Response: The DOI modeling is inaccurate – see response to Condition 10(c). We believe the cumulative results are inappropriate – see response to Comment 6, Paragraph 2.

Comment 46: NPS' analysis of addition of ASOFA+SCR with reheat and using NDDAQ modeling results yields a cost-effectiveness of \$4.0 – \$9.6 million per dv at Theodore Roosevelt NP and \$2.3 – \$5.5 million per dv cumulatively when Lostwood WA is included. We believe that our cost estimates indicate that addition of SCR with reheat is reasonable based upon BART determinations and proposals we have seen nationwide to date.

Response: See response to Comments 10(c), Comment 6 and Comment 9.

Comment 47: The great disparity between modeling results produced by BEPC/NDDAQ and NPS requires resolution.

Response: See response to Comment 10(c).

<u>M.R. Young Station Unit 1</u>

Comment 48: We have estimated that the proposed new wet scrubber will result in an approximately 1.8 dv improvement in visibility at Theodore Roosevelt NP and 3.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **<u>both</u>** 95% control **<u>and</u>** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 49: NDDAQ proposes that NO_x emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

Response: The proposed limit is under normal operating conditions without the ASOFA and SNCR, since the SNCR cannot be operated until the proper boiler temperature is reached. The actual startup emissions will be much higher (>1.0 lb/10^6 Btu). Therefore, limiting startup emissions based on normal operations with SNCR ($\leq$0.35 lb/10^6 Btu) will provide no relief to the source during startup.

Comment 50: NDDAQ underestimated the effectiveness of adding ASOFA + SCR to MRYS #1. We suggest that ASOFSA + SCR can achieve 0.05 lb/mmBtu.

Response: See response to Comment 8. The Department used 90% for ASOFA + SNCR.

Comment 51: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we also estimated a total annual cost for ASOFA + SCR with reheat at $9.7 million and $1,028 per ton.

Response: Minnkota has provided its own estimate of the cost of SCR as part of the BACT process under their Consent Decree. Minnkota's estimate has been included in the BART determination.

Comment 52: We believe that ASOFA + SCR with reheat represents BART for MRYS #1.

Response: Based on the Department's evaluation of the five statutory factors, we believe SCR + ASOFA is not BART. As explained in the Department's analysis, the cost effectiveness is excessive, the incremental cost over the next most efficient control option (ASOFA + SNCR) is excessive and there is very little visibility improvement especially when the Department's cumulative visibility modeling is considered (0.01 deciviews average in the 20% worst days). The cumulative modeling results represents the most realistic degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

M.R. Young Station Unit 2

Comment 53: NDDAQ is proposing upgrading the existing wet scrubber to limit SO_2 emissions to 0.15 lb/mmBtu **or** 95% reduction on a 30-day rolling average basis. We have estimated that the proposed scrubber upgrade will result in an approximately 1.2 dv improvement in visibility at Theodore Roosevelt NP and 2.2 dv cumulatively when Lostwood WA is included. We commend NDDAQ for the proposed new wet scrubbers, but recommend that the limits require **both** 95% control **and** 0.15 lb/mmBtu, as well as specific caps on emissions.

Response: See response to Comment 13.

Comment 54: NDDAQ proposes that NO_x emissions be limited to 3,995.6 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

Response: See response to Comment 49.

Comment 55: NDDAQ underestimated the effectiveness of adding ASOFA + SCR to MRYS #2. We suggest that ASOFSA + SCR can achieve 0.05 lb/mmBtu.

Response: See response to Comment 8.

Comment 56: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we estimated total annual costs for ASOFA+tail-end SCR with reheat at $15.6 million and $898 per ton.

Response: Minnkota has provided a much more detailed cost estimate of SCR with reheat as part of their BACT process under their Consent Decree. This estimate has been used in the Department's BART determination.

Comment 57: We believe that ASOFA + SCR with reheat represents BART for MRYS #2.

Response: Based on the Department's analysis of BART for MRYS Unit 2, we believe the cost effectiveness of ASOFA + SCR is excessive, the incremental cost over the next most efficient option (ASOFA + SNCR) is excessive and the visibility improvement is very small going from ASOFA + SNCR to ASOFA + SCR (see Department's final analysis). Therefore, we believe ASOFA + SCR is not BART.

__Modeling__

Comment 58: NDDAQ indicates that the purpose of the hybrid modeling is as weight of evidence to discount the impact of international (particularly Canadian) emissions and to better represent plume dispersion from point sources, particularly those closer to the Class I areas. While the CMAQ 36 km grid resolution does allow dilution of the plumes from point sources, ND's hybrid modeling assumptions raise more questions that are answered. CALPUFF does allow tracking of individual plumes but the model chemistry is much simplified compared to CMAQ and the methods required to normalize CMAQ results to CMAQ-CALPUFF hybrid results becomes quite elaborate and questionable.

Response: To address commenter's concerns, Sections 8.5.6 ("Normalizing Hybrid Model RRF to WRAP CMAQ RRF") and 8.6 ("The Impact of International Sources on North Dakota Class I Areas") of the draft SIP have been combined and extensively rewritten in a new Section 8.5.6. The purpose of this revision is to clarify the usage and purpose of the NDDoH hybrid modeling system. The emphasis of the rewrite is that the hybrid model was used only to adjust WRAP CMAQ results, and not as a "stand alone" system. We believe the new language helps to clarify the intent and legitimacy of the NDDoH hybrid modeling approach. The NDDoH also notes that values used for background ammonia and other input settings for CALMET-CALPUFF (including "alternative protocol" settings of ongoing concern to EPA and FLMs) become less critical as the effect of values used both in the numerator and denominator to a significant extent "cancel out" in the adjustment ratio applied to WRAP CMAQ results. Certainly, these settings will have less impact than if the hybrid model was used in a "stand alone" sense.

We raise the following technical issues with the CALPUFF application:

A) Ammonia is known to be an important input to determine the amount of ammonium nitrate (NH_4NO_3) formed in CALPUFF. Regional ambient concentrations of ammonia are poorly understood. ND has one ammonia monitor at Beulah; please describe the type of monitor and the land use at Beulah compared to other areas of the CALPUFF domain. We question if this monitor is representative of the CALPUFF domain. We note that monthly average NH3 from 2001-2002 was used as background ammonia in CALPUFF after removing days influenced by a source region. The draft Plan should identify that source region.

Response: The ammonia monitor at Beulah is a Thermo Scientific 17c continuous sampler, based on the chemiluminescence analytical process. Land use in the vicinity of the Beulah monitoring site is predominantly rangeland and cropland, which is typical for most of North Dakota. Land use in the State is relatively homogenous, with cropland slightly more common than rangeland in eastern and northern parts of the State, and rangeland slightly more common than cropland in the southwest part of the State. As such, the Beulah ammonia monitor should be representative of the Calpuff domain. When processing Beulah monthly background ammonia values to use with CALPUFF, hourly observations associated with the northwest wind-direction quadrant were filtered from the 2001-2002 data set. This was done to avoid bias due to the Great Plans Synfuels plant located about eight kilometers northwest of the monitor site. This plant produces significant amounts of ammonia as a result of its production process.

B) EPA disapproved the use of the Ammonia Limiting Method to define NH3 levels in the VISTAS application cited by NDDAQ.

Response: The NDDoH did not use the Ammonia Limiting Method (ALM) to define ammonia levels. Background ammonia for NDDoH hybrid modeling was based on actual ambient ammonia monitoring data. The NDDoH used the ALM simply to avoid double-counting of ammonia by multiple puffs in the modeling domain.

C) For POSTUTIL, hourly ammonia data for 2001 -2003 were used and the Plan does not mention removing data. The Plan should identify if different years were used for the two applications. It appears that the ammonia levels at Lostwood were doubled compared to measured values based on the expectation that Lostwood is closer to ammonia sources in Canada. However, that adds a subjective adjustment to the CALPUFF modeling that brings into question the presumption that CALPUFF modeling is more accurate than just using CMAQ at 36 km.

Response: Based on consultation with Joe Scire (TRC Atmospheric Studies Group), the NDDoH elected to use hourly background ammonia data (Beulah monitor) with POSTUTIL. Use of the hourly data (rather than monthly) tended to improve hybrid model agreement with sulfate and nitrate observations in the performance evaluation. As was the case in the ammonia data set used with CALPUFF, hourly data associated with the northwest wind direction quadrant were removed from the data set used with

POSTUTIL, because of bias due to a large ammonia source (Great Plains Synfuels Plant) located northwest of the Beulah monitor site. Due to resultant missing data periods, the three year period 2001-2003 of hourly ammonia data was averaged to prepare a composite hourly data set for 2002. The NDDoH considers this a refinement of the monthly data used with CALPUFF, and notes that ammonia background used with POSTUTIL completely supersedes the ammonia background used in CALPUFF (this conclusion is the result of extensive testing).

Regarding adjustment of Beulah monitoring data for the Lostwood location, the assumption of higher ammonia background at Lostwood is consistent with predominant land use and other anecdotal evidence (see Section 8.5.4), and it provided better agreement with observations in hybrid model performance evaluations for sulfate and nitrate. We note again that NDDoH hybrid modeling is not as sensitive to the specific ammonia background applied because of the ratio approach used to adjust WRAP CMAQ results (see response to Comment 58).

D) We note that four ozone monitors in central ND were selected to represent background ozone in CALPUFF. Are there only four ozone monitors in the CALPUFF domain? Table 8.6 says background value for ozone was 30 ppb, but does not link this to monitoring data.

Response: The four ozone monitors used to represent background ozone in the hybrid model (CALPUFF) are located near the primary transport path between larger North Dakota point sources and Class I areas. Though the NDDoH operates additional ozone monitors in the State, ozone observations are relatively homogeneous across North Dakota with little spatial variability. It is not likely that the inclusion of data from additional ozone monitors would have provided any meaningful difference in results. The NDDoH used hourly ozone data from the four monitors for year 2002 with CALPUFF. The 30 ppb background ozone number in Table 8.6 represents a typical annual average monitored value, and applied only in those rare cases when the hourly value was missing.

Comment 59: We question the Hybrid model performance evaluation. Model performance evaluations are usually based on raw model output. We understand that the Hybrid model results were normalized before evaluation and then were normalized again to the WRAP baseline results. The need to normalize the CALPUFF relative response factors to the WRAP results, brings into question the value of using the CALPUFF hybrid regional model to discern the benefits of NDDAQ strategies.

Response: The performance evaluation was based on raw model output from the hybrid system. Model output was not normalized or adjusted in any way prior to comparing with observations. Language has been added to Section 8.6 to clarify this point.

Comment 60: Section 8.6, including Figure 8.10, describes a possible way to account for international emissions when assessing the progress toward the goal of natural conditions. While we agree that examining the contribution to extinction for each aerosol species is a good approach to understanding if a State is meeting its fair share of emissions reductions associated with visibility impacts at a Class I area, the method described in this section and in the figure raise concerns since there was no assessment of the international component of the natural condition estimate. The value in 2064 illustrated in Figure 8.10 uses the same natural condition endpoint for the total extinction as well as the "U.S. Source" extinction, yet the 2064 natural condition estimates for aerosol species include some global or international component. We believe that a better way to address reasonable progress by extinction component is to assess the reduction needed for each aerosol species measured in the baseline period to the end of the first planning period and then assess if a state's plan achieves a comparable reduction for its share of extinction at the Class I areas.

Response: In its approach for discounting the impact of Canadian source visibility-affecting emissions, the NDDoH modified the emissions inventories used in the adjustment of WRAP CMAQ modeling results (see revised Section 8.5.6). The modification involved elimination of all Canadian sources, except for the Canadian component of natural background, which was retained through adjustment of boundary conditions in CALPUFF. Therefore, the modified emissions inventories accounted for all non-Canadian sources, including all components of natural background. Thus, there was no need to adjust the end point for the "U.S. sources" glide path. For clarification, however, further description regarding the context of "U.S. sources" has been added to Section 8.6, and labels for "U.S. sources" glide paths in Figures 8.10, 8.24, 8.26 and 8.27 have been changed to "Canadian Sources Discounted Glide Path".

<u>Reasonable Progress Goals</u>

Comment 61: The State should rely on WRAP regional modeling as the primary tool for demonstrating progress toward visibility improvement goals. The CMAQ-CALPUFF hybrid modeling is problematic in several ways and gains ND little benefits compared to using WRAP products. Two WRAP products that were omitted but should be included to help ND in making its reasonable progress determination are 1) Weighted Emissions Potential (WEP) and 2) extinction glide paths for SO_4, NO_3, and OC.

The uniform rate of progress glide path cannot be revised to account for contributions from natural sources or international sources under current or 2018 conditions without also removing these contributions from the 2064 endpoint. While the contribution from natural and international sources by 2064 is unknown, it may be comparable to current contributions. Therefore removing the estimated contributions from current conditions without also accounting for those contributions to the 2064 endpoint inappropriately changes the slope of the uniform rate of progress

It would be more appropriate to use the WRAP CAMx-PSAT results to demonstrate the relative contributions to sulfate and nitrate from Canadian and ND emissions at the North Dakota Class I areas. The Plan has already included these results in Table 6.7.

We suggest NDDAQ use the WRAP extinction glide paths to show the improvement in SO_4 or NO_3 due to emissions reductions from all sources in the WRAP 2018 inventory, and compare the ND emissions reductions by 2018 to emissions reductions from Canada and neighboring states.

It would be informative for the Plan to include what percent of the State's total SO_2 and NO_X emissions from point sources is being reduced under BART. What other point source or area source reductions are reasonable?

Response: The usage and purpose of the NDDoH hybrid modeling system was clarified in the response to Comment 58, and in the revision of Section 8.5.6 of the SIP. The NDDoH does not agree that the NDDoH modeling provides little benefit compared to using WRAP products. Through use of the hybrid model to adjust WRAP CMAQ results, the NDDoH was able to produce a suite of analyses related to weight of evidence, none of which were available in the original WRAP products. The NDDoH regards these weight of evidence analyses more useful than the additional WRAP products suggested by the commenter.

Regarding the uniform rate of progress glide path 2064 endpoint, see response to Comment 60.

The SIP already includes the WRAP Cam_x-PSAT results, demonstrating the relative contributions to sulfate and nitrate from Canadian and ND emissions at North Dakota Class I areas, in Table 6.7 and 9.12.

A comparison of North Dakota emissions reductions by 2018 with emission reductions from Canada and neighboring states has been added to Section 9.

The Department has reviewed other point sources, agricultural tillage operations, smoke management techniques and oil and gas operations for possible air pollution control requirements. The Department determined that additional controls were not reasonable during this planning period. However, all sources of emissions will be reevaluated during future planning periods.

Comment 62: For stationary sources, NDDAQ developed a methodology to look at options for controls for sources, beyond the source subject to BART, contributing to the major components of aerosol extinction on the worst 20 percent days. While we generally agree with the use of emissions over distance (Q/d) as a screening tool, we note that the Heskett facility was not included in Table 9.4 even though NDDAQ proposes to exclude the source from BART requirements.

Response: The status of Heskett Unit 2 is being reevaluated and will be addressed in a supplement to this SIP revision.

Comment 63: Table 9.9 summarizes the results of assessing the costs and visibility improvement associated with possible controls on these facilities. The two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar, if not greater than, BART sources that will be required to add controls. The methodology to calculate visibility improvements noted in Table 9.9 are not explained in this section but appear to be some calculation of changes in the long-term metric of the 20 percent worst visibility days. These sources likely contribute to higher impacts on a daily basis, and a reduction in their emissions would be part of a broad strategy to reach natural conditions at the Class I areas. As such

NDDAQ should examine the total improvement from the suite of sources as part of its reasonable progress assessment, not a simple unit by unit approach.

Response: The improvement in the 20% worst days was used to indicate the amount of visibility improvement. The SIP was revised to better explain this. Addressing individual days under reasonable progress is inconsistent with the reasonable progress goals in 40 CFR 51.308(d)(1) which states “The reasonable progress goals must provide for improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.” 40 CFR 51.301 defines the most impaired days as meaning “the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the highest amount of visibility impairment.” 40 CFR 51.301 defines the least impaired days as the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the lowest amount of visibility impairment.” It is clear that reasonable progress goals should be established based on the average of the “most impaired days” and the “least impaired day”, not individual days.

The Department did evaluate the cumulative effects of the most efficient remaining options. As stated on p. 182, the cumulative visibility improvement was 0.11 deciviews at LWA and 0.03 deciviews at TRNP. The less efficient control options would provide even less improvement.

Comment 64: The assessment of non-air quality impacts on page 181 in the draft SIP does not address the substantial human health benefits associated with reductions in fine particulate concentrations resulting from additional control of SO_2 and NO_X emissions from Coyote and AVS since they would become the newest and highest emitters of these pollutants after implementation the SIP as drafted.

Response: Reasonable progress is evaluated based on four stationary factors 1) the cost of compliance, 2) the time necessary for compliance, 3) the energy and nonair quality environmental impacts of compliance, and 4) the remaining useful life of the source.

The Energy and Non-Air Quality Environmental Impacts Analysis does not address health effects from air emissions. As stated in the BART guideline “In the non-air quality related environmental impacts portion of the BART analysis, you address impacts **other than air quality** [emphasis added] due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device.”

Even though health effects are not evaluated under this section of the BART analysis, the Department reviewed ambient monitoring data in the vicinity of Antelope Valley Station and Coyote Station. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hour SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS) and the maximum annual average was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average was 2.7 ppb (5.1% of the NAAQS). Given the low concentration of these pollutants, any benefits to health from additional controls and these facilities would be extremely hard to quantify.

Comment 65: The decision on additional point source controls would be better informed by analysis of the how the emissions from sources within the State contribute to nitrate and sulfate concentrations in Class I areas, both inside and outside of the State, in the baseline period compared with the model projections in 2018. If BART controls on stationary sources as well as expected reductions from Federal mobile source, small engine, and fuel requirements would achieve a reduction that, had all other contributing States and other regions met similarly, would put the total aerosol extinction on the uniform rate of progress path, then the State could better support a limited approach to additional controls in this first planning period. However, based on our review of the information supplied in the draft Plan and its appendices, we believe there are cost-effective controls for the Coyote and AVS facilities that should be implemented under the reasonable progress provisions.

Response: The Department reviewed these sources based on the four statutory factors. We looked at the visibility improvement using an emissions inventory that included all contributing sources (cumulative analysis). This analysis showed very little improvement if additional air pollution controls (SO_2 and NO_x controls) are installed. We believe an individual analysis for SO_4 and nitrate will show the same result.

Although the Department found (using the four statutory factors) that additional controls are not reasonable, Otter Tail Power Company has committed to reduce NO_x emissions at the Coyote Station by approximately 35%. This requirement will be included as part of this SIP revision. In addition, all sources will be reevaluated during the next planning period.

<u>Long-Term Strategy</u>

Comment 66: On Page 184, there is discussion of the reduction in sulfur dioxide emissions from the R.M. Heskett Station No. 2. As noted earlier, we believe this facility is subject to BART and should be assessed under the BART provisions. In addition, the reduction in emissions reflect a 21 percent reduction from current emissions. The 70 percent coal-to-stack removal cited in the draft Plan implies a greater reduction from current emissions.

Response: The status of Heskett 2 is being reevaluated and will be addressed in a supplement to this SIP revision.

Comment 67: We request that NDDAQ include in the Long-Term Strategy a linkage between the prevention of significant deterioration program and its assessment of visibility impacts and the Regional Haze Plan in the SIP. This will ensure that new sources are reviewed in a manner that does not jeopardize the reasonable progress goals established by this Plan.

Response: As part of the PSD program, the Department will evaluate the cumulative effect of all sources on the 20% worst and 20% cleanest days to ensure there is no degradation from baseline conditions. This has been added to the Long-Term Strategy as Paragraph 10.7.